# Memorandum

**To:** Intermountain Power Service Corporation (IPSC) File (N327010)

**From:** Milka Radulovic, Environmental Engineer

**Through:** Rusty Ruby, NSR Section Manager, R 10/14/04

Regg Olsen, Permitting Branch Manager RDO 10/14/04

**Date:** October 14, 2004

**Re:** Response to Comments received on IPSC Intent to Approve number DAQE- IN327010-04

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On April 1, 2004, a public comment period began to solicit comments on Intent to Approve (ITA) Intermountain Power Service Corporation's (IPSC) addition of New Unit 3 at their existing Intermountain Power Plant (IPP), located in Delta, Millard County, Utah. The IPSC proposed an electricity-generating unit with a pulverized coal fired boiler to provide 950 MW gross (900 MW net nominal) of electrical power. At the Millard County Economic Development Director's request a public hearing was held on April 29, 2004. The public hearing found overwhelming support for the new unit from the local population, medical and educational community.

In accordance with public request, the comment period was extended by twenty one (21) days.

On June 3, 2004, an additional 30-day comment period was started, to address shortcomings in the previous public notice of April 1, 2004.

Numerous comments were received, both during the comment period and at the public hearing. All comments received during the two public comment periods and the public hearing are listed here, with the original comments being included as an attachment. Following each comment is the Utah Division of Air Quality's (UDAQ) response, along with any action taken by the Division in regards to the final Approval Order (AO).

Quoted items are taken verbatim from the original comment submission. If the comment was unclear, UDAQ attempted to explain the comment as understood by the Division.

UDAQ responded to the following comments:

Comments made during the public comment periods (PCP) from April 1 to May 21 and from June 3 to July 3, 2004, and the public hearing (PH) of April 29, 2004.

Comments by Utah Chapter Sierra Club, Wasatch Clean Air Coalition, Grand Canyon Trust, Rocky Mountain Office of Environmental Defense, Western Resource Advocates, and Clean Air Task Force of May 20, 2004 (UWG). Our responses to UWG comments of May 20, 2004 also provide, by reference, responses to UWG comments of April 14, 2003. On April 14, 2003, UWG submitted comments regarding the December 23, 2002 Notice of Intent (NOI) for the IPP Unit 3. However, the IPP Unit 3 project was not available for public comment until April 1, 2004. Nevertheless, UDAQ has considered these comments as well.

Comments by UWG of June 30, 2004 and July 16, 2004.

Comments by National Park Service (NPS) of May 27, 2004. Our responses to NPS comments of May 27, 2004 also provide, by reference, responses to NPS comments of March 25, 2004.

Comments by Environmental Protection Agency (EPA) of May 24, 2004.

Comments by Intermountain Power Service Corporation (IPSC) and Intermountain Power Agency (IPA) of May 21, 2004.

Modeling questions made in the above referenced documents were reviewed and responded to by the UDAQ Technical Analysis Section. These responses are provided in the file.

**Comment #1**

Sixty-one individuals and seven groups submitted comments expressing general approval of the proposed project. (PCP/PH)

Response

The comments were noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the Approval Order (AO).

**Comment #2**

One individual submitted comment of general opposition to the new unit. (PCP/PH)

Response

The comment was noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

**Comment #3**

A representative of UWG made a number of specific comments on the ITA during the public hearing. (PCP/PH)

Response

Response to these comments is incorporated in the response to the identical written comments submitted by the same group starting with Comment 6.

**Comment #4**

One individual questioned why the amount of mercury emitted in California was much smaller that the proposed emissions of mercury from the Unit 3. The commenter wanted to know if the mercury emission from the Unit 3 would be controlled to the level comparable with California. (PCP/PH)

Response

Emissions of mercury will be reduced to the maximum achievable control technology level in accordance with the EPA proposed rule, 40 CFR Parts 60 and 63, National Emission Standards for Hazardous Pollutants; and, in alternative Proposed Standards of Performance for New and Existing Stationary sources: Electric Utility Steam Generating Units (69 F R 4652 - 4752 January 30, 2004). No data was submitted by the commenter to support a suggestion that a higher level of mercury emission reduction is achievable for Unit #3. No changes were made to the AO.

**Comment #5**

One individual expressed concern about the "yellow/brown cast to the wide sky" and "plume of smoke that fills up the valley". The commenter is "urging" UDAQ "to take into account the amount that is foisted into our lives". (PCP/PH)

Response

The comment was noted. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

**Comment #6**

> "IPSC failed to submit a complete permit application and thus consideration of the permit application is premature." (UWG, p.2)

Response

All information submitted by IPSC was considered in the technical review by UDAQ. The application was deemed to be administratively complete before the draft Approval Order was available for public comment. The public had full opportunity to comment on all aspects of the Approval Order. No changes were made to the AO.

**Comment #7**

> "According to 40 CFR 51.307, UDAQ should have provided the FLM with all information relevant to the permit application at least 60 days prior to the April 29 public hearing…" (NPS, p.13)

Response

Consistent with the requirements of R307-406-3(1), UDAQ provided the Federal Land Manager (FLM) with all information relevant to the NOI, including the ITA (draft AO) and staff analysis, 60 days prior to the April 29 public hearing. Further, UDAQ provided the FLM the opportunity to submit a visibility analysis within 30 days of the UDAQ's preliminary determination and before announcing the public comment period. We list some of the key communications to the FLM:

- On December 06, 2002, UDAQ staff had a pre-application meeting regarding IPP Unit 3 with representatives of IPSC, NPS, EPA Region 8, and UAMPS.
- On December 23, 2002, UDAQ submitted the NOI for IPP Unit 3, dated December 14, 2002, to NPS.
- On May 30, 2003, UDAQ submitted Addenda to the NOI, dated May 14, 2003 and May 27, 2003, to NPS.
- On June 20, 2003, UDAQ sent Replacement of the NOI Sections 7 & 8 and Appendix E to NPS.
- On March 1, 2004, before the NPS, UDAQ and IPP meeting of March 4, 2004, UDAQ e-mailed a draft Modified Source Plan Review to NPS.
- On April 1, 2004, UDAQ published the first Public Notice and on June 3, 2004 the second one.
- On April 29, 2004, UDAQ held a Public Hearing.

The submitted documents had all information relevant to the IPP Unit 3 permit application, including analyses of the anticipated impacts on visibility in Federal Class I areas. In addition, UDAQ communicated to NPS additional relevant information in numerous phone conversations and e-mails e.g. on October 31, 2003, November 3, 2003, November 4, 2003 etc.

In summary, UDAQ provided the FLM with all information relevant to the permit application in a timely manner. No changes were made to the AO.

**Comment #8**

> "Public notice lacks certain information required by Utah Air Quality Rules." (EPA, p.7)

Response

UDAQ responded to this comment by adding to the public notice of April 1, 2004 the relevant information; the public notice of June 3, 2004 incorporates all the required information. A second comment period was conducted to ensure the public was aware of and could consider all information required by Utah rules. No changes were made to the AO.

**Comment #9**

> "BACT definition and process" (NPS, p.5)

Response

The commenter cites two statements of EPA policy from the 1990 draft New Source Review Workshop Manual:

- *"Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternative."*
- "A permitting authority does have *"the discretion to engage in a broader analysis if they so desire.""*

UDAQ recognizes these statements of EPA policy. As no legal or technical issue was raised with respect to the ITA, no changes were made to the AO.

**Comment #10**

> "Clean Coal Technologies" (NPS, p.6)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information, UDAQ has concluded that Integrated Gasification Combined Cycle (IGCC) and Circulating Fluidized Bed (CFB) have been considered appropriately. There are three relevant facts:

- IGCC and CFB would require redefining the design of the source.
- Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.
- Even if a top-down BACT analysis were required, both IGCC and CFB would be eliminated.

**Comment #11**

> "Circulating Fluidized Bed" (NPS, p.7)

Response

Please see the response to Comment #10 above. Based on all available information, UDAQ has concluded that CFB boilers have been considered appropriately. Additionally, a top-down analysis including CFB as an available option, though not required, was provided by IPP. This analysis shows that CFB would not be appropriate for the IPP project. Also, CFB boilers are no more effective than new PC boilers in controlling emissions of most regulated pollutants. At this point in time, the new emission limits for the IPP Unit 3 are the most stringent emission limits, that we are aware of, imposed by any permit, granted or pending, on pulverized coal-fired boilers in the U.S.A.; these emission limits compare favorably to the emission limits for CFB boilers.

**Comment #12**

> "Federal and state clean air laws require IPSC to consider the application of production processes and available methods, systems and techniques to lower airborne contaminants." (UWG, p.3)

Response

Please see the responses to Comments #9 and #10.

UDAQ recognizes and strictly applies both federal and state clean air laws regarding the application of production processes and available methods, systems, and techniques for control of pollutants. For example, we have reviewed and approved the proposed application of production processes such as fuel combustion techniques: ultra low $NO_x$ burners and over-fire air. We have also reviewed and approved the proposed application of methods, systems, and techniques such as add-on controls: wet limestone flue gas desulphurization, selective catalytic reduction, and fabric filter baghouses. The text of the comment, however, identifies one particular production process that the commenter feels should be included in the BACT analysis: IGCC. UDAQ has reviewed this issue and has concluded that neither federal nor state clean air laws require this. Nevertheless, we did review an analysis of IGCC as a part of our permitting process.

That IGCC is not structurally similar in design and capacity to other coal-fired facility is generally understood. IGCC is not based on coal combustion but on coal gasification; the two processes are fundamentally different. Furthermore, IGCC and pulverized coal (PC) units cannot use the same control technology.

The commenter quotes from CAA 165(a)(4) and 40 CFR 51.166(j) to demonstrate that any major emitting facility is subject to BACT. UDAQ agrees.

The commenter quotes from Utah rules a paragraph defining BACT and concludes, "Thus, the BACT requirement must be implemented and construed under Utah law at least as strictly as EPA and the federal courts have construed it." UDAQ agrees.

The commenter then states, "This definition includes coal gasification." UDAQ does not agree. Further, the practice of environmental protection authorities over the years does not support it either.

The commenter also quotes the Ninth Circuit Court in *Citizens for Clean Air v. EPA*, "initially the burden rests with the PSD applicant to identify the best available control." Similarly, they quote from an EPA guidance document. UDAQ agrees that the applicant must identify the best available "control" and consider all possible control alternatives for the proposed source. In this case the proposed source is a PC boiler.

The commenter then quotes from the 1990 draft New Source Review Workshop Manual (p. B.5) to show that "the applicant *must* consider all "available" control options". We repeat the quote (emphasis added):

> "*The first step in a "top-down" analysis is to identify, **for the emission unit in question** (the term "emission Unit" should be read to mean emission unit, process or activity), **all "available" control options**. Available control options are those air pollution control technologies or techniques with a **practical potential for application to the emission unit** and the regulated pollutant **under evaluation**. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for **control** of the affected pollutant. This includes technologies employed outside of the United States. As **discussed later**, **in some circumstances inherently lower-polluting processes** are appropriate for consideration as available control alternatives."*

The draft Workshop Manual states clearly "*all 'available' control options*" "*for the emission unit in question*". It also says "*with a practical potential for application to the emission unit …under evaluation*". As shown by these passages from the draft Workshop Manual, EPA's interpretation of the statutory BACT requirement is that the applicant must consider all available control options but only for the emission unit in question. UDAQ adopts a similar interpretation. In this case, the unit in question is a pulverized coal-fired boiler. Also, "*production processes or available methods, systems, and techniques*" are "*for control of the affected pollutant*". And finally, it says "*as discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives*." This later discussion clarifies the circumstances: "*Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.*" IGCC application would require redefining the design of the source.

The commenter next quotes from several sources to suggest that the meaning of the term "available" includes IGCC.

First, they refer to the U.S. EPA Environmental Appeals Board (EAB) decision In re: Maui Electric Company, which in turn quotes from the draft Workshop Manual at p. B.17. We agree that IGCC could be obtained by the applicant "through commercial channels." However, it is not an available control technology and it is not appropriate for consideration in the BACT analysis for the source under consideration.

Second, they refer to the EAB decision In re: Knauf Fiber Glass, which in turn quotes from the Manual at p. B.5; the commenter provides a quote that we repeat with our own emphasis added:

> *" "available" is used in the broadest sense under the first step and refers to **control options** with a "**practical potential** for application to the **emission unit"***

> ***under evaluation****….The goal of this step is to develop a comprehensive list of control options."*

As above, we find the plain language of the Manual clear. U.S. EPA's interpretation, as set forth in the draft Workshop Manual, is that the scope of the BACT analysis is limited to control technologies that can be applied to the emission unit proposed by the applicant. IGCC is not a control option with a practical potential for application to the emission unit under evaluation i.e. a pulverized coal-fired boiler.

Third, the commenter quotes from the EAB decisions In re: Spokane Regional Waste-to-Energy Applicant and two other appeals of BACT determinations for municipal waste combustors; the commenter presents a quote that we repeat (emphasis added):

> "Under the top-down methodology, applicants must apply the best available **control** technology unless they can demonstrate that the technology is technically or economically infeasible. The top-down approach places the burden of proof on the applicant to justify why the **proposed source** is unable to apply the best technology available."

In response, UDAQ first notes that quote does not accurately reflect the BACT requirement under the PSD statute and regulation. Second, UDAQ does not find that IGCC is a "control technology," such as baghouses, electro-static precipitators (ESPs), cyclones, etc.; Unlike these control technologies, application of IGCC would require replacement of the proposed source in its entirety.

As required by state and federal law, UDAQ has thoroughly evaluated all available control measures potentially applicable to the proposed unit i.e. the pulverized coal-fired boiler.

We find that, contrary to the commenter's contention that the definitions of BACT under Utah and federal law, and the core requirements of the BACT analysis under federal case law, EPA adjudicatory decisions, and the New Source Review Manual, do not demonstrate or even imply that an available technique such as IGCC must be identified and evaluated as a control option in the first step of the BACT analysis.

UDAQ finds that the analysis of IGCC, as was done, is sufficient and that broader analysis is not required.

**Comment #13**

> "Recent state actions requiring consideration of IGCC establish irrefutable precedence for the consideration of IGCC." (UWG, p.6)

Response

UDAQ has reviewed this comment and the presented information. Recently, the permitting authorities of two states, Illinois and New Mexico, have decided to exercise their discretion and request the applicants include IGCC in their BACT analyses. The results of the requested BACT analyses are not available yet. Regardless of the outcome of those analyses, the interpretations made by other permitting authorities implementing the BACT requirement under other states' regulations have no effect in Utah.

In other recent applications for coal-fired units, the permitting authorities have not requested the applicants include in their BACT analysis production processes different than the proposed one. These states are Kansas, Missouri, Montana, Wyoming, Kentucky, Wisconsin, Arkansas and West Virginia. Also, as mentioned previously, although not required, the applicant provided and we reviewed a detailed analysis of IGCC.

**Comment #14**

> "IPP failed to correctly address IGCC in the BACT analysis and the permit must be denied. A properly conducted BACT analysis shows IGCC is BACT for the IPP project." (UWG, p.8)

Response

UDAQ has reviewed this issue in light of the comment. As discussed in the response to Comment #12 above, UDAQ has concluded that IGCC has been properly addressed. Additionally, a revised top-down analysis, though not required, has been provided by IPP. This analysis shows that IGCC would not be appropriate for the IPP project.

**Comment #15**

> "UDAQ and IPSC should have considered a supercritical pulverized coal boiler for the new unit." (UWG, p.22)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information and the discussion above, UDAQ has concluded that supercritical pulverized coal boilers have been considered appropriately. Additionally, a top-down analysis including supercritical boiler technology, though not required, was provided. That analysis shows that supercritical boilers would not be appropriate for the IPP project. Also, supercritical boilers are no more effective than sate-of-the-art subcritical boilers in controlling emissions of regulated pollutants. At this point in time, the new emission limits for the IPP Unit 3 are the most stringent emission limits, that we are aware of, imposed by any permit, granted or pending, for a pulverized coal-fired boiler in the U.S.A.., whether subcritical or supercritical. For example, see the proposed emission limits for supercritical boilers in three recently issued or pending permits: MidAmerican Energy, Longview Power, and Elm Road.

The paper by Bartolomei, referenced in the comment, provides information on expected rates and not on emission limits. In addition, the statements by Bartolomei are opinions and not commercial offers backed-up by guaranties. Thus, they are not properly part of a BACT analysis except for general information.

The commenter points out the proposed emission limits for the planned Steag facility to reinforce their comment. We have reviewed the PSD permit **application** for Steag Power's Desert Rock Energy facility and there are some issues that we point out regarding this application. First, this is only an application; the permitting process is in a very early stage. Obviously, the existence of a permit application, with no issued permit and no facility, does not provide any information that is informative as to technical feasibility and achievability of a particular emission limit. Second, the application seems to be substantially inconsistent regarding the sulfur dioxide emission limits. For example, we find the following statement on page 4-11: "Steag is proposing to limit $SO_2$

emissions to 0.06 lb/MMBtu as a 30 day average and 0.09 lb/MMBtu as 24-hour average…" However, on page 6-3, we find that 0.06 lb/MMBtu is listed as an annual average and 0.09 lb/MMBtu as a 3-hour average. Then, in Table 3-2 of Attachment 3, we find that 0.06 lb/MMBtu is listed as a 24-hour average. Third, the application seems to propose an emission limit for a 30-day average and not for a 30-day rolling average; that is a substantially less stringent limit. Fourth, the predicted air quality impact from the proposed project is very high for Navajo Nation Territory. The sulfur dioxide concentration, based on 0.09 lb/MMBtu emission, is 76% of the PSD Class II increment for a 3-hour averaging period, as shown in Table 6-6a. This indicates a need for stringent limits beyond BACT. Finally, the Desert Rock Energy facility is a proposed mine-mouth plant implying less variable coal quality and, in particular, less variable sulfur content than for the IPP Unit 3. For all these reasons, we believe that the proposed sulfur dioxide emission limits for the Desert Rock Energy facility have only a limited relevance at present.

Finally, the commenter states, "Xcel Energy is also **considering** the construction of a supercritical boiler for a new proposed unit at its Comanche plant in Pueblo, Colorado" (emphasis added). This is not sufficient to include in a BACT analysis.

**Comment #16**

> "The ITA fails to address carbon dioxide and other greenhouse gas emissions." (UWG May 20, 2004, p.22 and UWG June 30, 2004, p.2)

Response

UDAQ reviewed this issue in light of the comments of May 20, 2004, the supplemental comments of June 30, 2004 as well as the second supplemental comments of July 16, 2004. The second supplemental letter provided a copy of Petitioners' Appellate Brief in Commonwealth of Massachusetts v. EPA, Civil Action No. 03-1361 (D.C. Cir.). It was received after the closing of the second comment period and therefore did not need to be considered by UDAQ. Nevertheless, based on all available information, we found it proper that the ITA did not address greenhouse emissions. UDAQ believes that regulating greenhouse gas emissions is not required. The reasons are as follows:

- Historically, permitting authorities have not considered greenhouse gas emissions;
- The Clean Air Act and by extension, EPA do not regulate greenhouse gas emissions;
- While there is a petition in the court requesting that EPA reconsider the issue, the court has not ruled yet; oral arguments are scheduled for April 8, 2005;
- It is not prudent for UDAQ to take any action until after the court ruling; indeed it would be ill advised to take any action prematurely.

UDAQ believes that the CAA, NSR provisions and Utah's administrative rules do not require regulating greenhouse gas emissions.

**Comment #17**

> "UDAQ and IPSC should have evaluated the use of K-fuels." (UWG, p.23)

Response

UDAQ has reevaluated the use of K-fuels in light of the comment. Based on all available information, UDAQ finds the following:

- The K-fuel is not even available for sale yet; the first plant is not scheduled to start operations until 2005;
- There is no commercial experience with this technology;
- The technology is complex and will pose significant technical and economic risks;
- The technology may eventually prove attractive for subbituminous coals; its advantages are more questionable for bituminous coal.

Therefore, we conclude that K-fuels are neither available nor technically and economically feasible for the IPP Unit 3.

**Comment #18**

> "UDAQ improperly eliminated use of lower sulfur coal based on unreasonable costs." (UWG, p.24)

Response

UDAQ has reviewed this issue in light of the comment. Based on all available information, we find that lower sulfur coal was justifiable eliminated based on economic impacts. The 1990 draft New Source Review Workshop Manual, referenced by the commenter, is a draft statement of EPA policy; it is not a part of EPA's or Utah's PSD regulations. UDAQ does not necessarily adhere to the prescriptive procedural "requirements" in this manual. Regardless, in this instance, the procedure used is consistent with that suggested by the Workshop Manual. Utah coal is the "base case" (or "baseline" as described in the 1990 draft Workshop Manual), and PRB coal is the only more stringent control technique being evaluated. Thus the difference in costs and $SO_2$ emissions between these two control techniques represents both the average cost effectiveness and the incremental cost effectiveness.

In addition, the projected sulfur content was used for calculations as seen in Table 1 on page 109 of the Modified Source Plan Review.

**Comment #19**

> "The $SO_2$ emission limits are not reflective of the maximum reductions achievable with the $SO_2$ wet scrubber." (UWG, p.25)

Response

UDAQ has reconsidered the sulfur dioxide BACT analysis and associated emission limits in light of the additional information provided by the commenters. We have also requested and obtained additional information from IPP. Based on all additional information, UDAQ believes that more stringent emission limits for sulfur dioxide are achievable with the proposed WFGD system on the IPP Unit 3. The following limits will be in the AO:

0.10 lb/MMBtu on a 24-hour block average and
0.09 lb/MMBtu on a 30-day rolling average.

These are the most stringent sulfur dioxide emission limits, that we are aware of at this point in time, imposed by any permit, granted or pending, for a pulverized coal-fired boilers in the U.S.A.

The commenter presents information on control efficiency achieved with the proposed SO2 control equipment. UDAQ properly applied BACT as defined at R307-101-2. Under the regulation, BACT is "an emission limitation" that is "based on" the maximum degree of reduction in emissions. An operational requirement, such as a minimum control efficiency, may be prescribed instead, if the reviewing authority determines that the imposition of a numerical emission limitation is infeasible. This is not the case for $SO_2$. In these instances, UDAQ imposes numerical emission limitations.

In addition, the commenter presents information on emission rates achieved at various existing pulverized coal-fired boilers. We have given full consideration to these data and, as a result, we have concluded that the appropriate BACT emission limits are those listed above. We recognize that these emission limits represent a nominal control efficiency that is numerically lower than that indicated by the actual emissions data from some existing, well-controlled boilers. This is by design and is necessary, because the BACT emission limit must be set at a level at which the source is able to achieve continuous compliance. The limit cannot be set at a level that represents the expected average actual emissions because the wource would then be out of compliance during some operating periods (i.e., whenever the emissions are above the long-term average). It is generally understood that an imposed limit must be greater than an achieved rate to account for variability. There are numerous sources of this variability. Some of them are: uncertainty in measurements, variability in coal, variability in performance of control equipment, variability due to aging of the plant, etc. None of the data presented by the commenter provide a demonstration that the IPP Unit #3, if properly designed and operated, can achieve continuous compliance with emission limits that are more stringent than those set forth in the AO.

Also, the commenter claims that "EPA's recently proposed BART guidelines propose 90-95% $SO_2$ removal at existing facilities as a retrofit requirement underscores that new facilities should be able to meet or exceed the 95% $SO_2$ removal requirement". A review of the proposed BART rule (Federal Register, Vol. 69, No. 87, May 5, 2004, pages 25199 and 25200) reveals the following:

- EPA proposes $SO_2$ emission limits not control efficiency for Western coals;
- EPA provides clear justification for this proposal;
- EPA considers a $SO_2$ emission rate of 0.10 lb/MMBtu for 0.7% sulfur Western coal demonstrated; this is the rate set by UDAQ for the IPP Unit 3.

**Comment #20**

"$SO_2$ Controls" (NPS, p.2)

Response

Please see the response to Comment #19 above.

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The $SO_2$ emission limit of 0.15 lb/MMBtu for 3-hour averaging period will be provided for NAAQS protection. It is enforceable and consistent with the proposed BACT emission limits but it is not part of BACT analysis.

Based on data provided in NPS Table 1.a. for 3-hour averages:

- The new emission limit for IPP Unit 3 is the same as the proposed emission limit for Hardin, Roundup, WYGEN2, and Longview boilers. The projected sulfur content of the design coals for these boilers, expressed as weight percent, are 0.75, 0.64, 0.94, 1.20 and 2.5, respectively; they vary substantially, yet the emission limits are the same. We believe that this is appropriate because of the unpredictable nature of 3-hour variability; the coal sulfur content is only one of the factors.

- The emission limit of 0.15 lb/MMBtu is very close to the emission rates achieved at Colstrip #3 & #4; the difference represents a reasonable safety factor provided to allow for continuous compliance.
- We have given proper consideration to the PSD permit application for Steag Power's Desert Rock Energy facility. However, Steag Power has only limited relevance; please see the response to Comment #15.

**Comment #21**

> "BACT emission limit for sulfur dioxide should be more stringent." (EPA, p.1)

Response

Please see the response to Comments #15, #19 and #20. These responses are supplemented with responses to specific paragraphs in the comment.

UDAQ has reconsidered the projected coal sulfur content. We have requested and obtained relevant information from IPP; the following quotes are from the IPP (Technical Memorandum, December 18, 2003):

> "It can be seen from Figures 2 and 3 that the average sulfur content of Utah coals shipped to both Intermountain and Hunter increased between the years 2000 and 2002. It can also be seen that the standard deviation of the sulfur content of the fuel shipments has increased during the same time period. An increase in the standard deviation of the fuel sulfur content points toward increased variability in the fuel sulfur content. As discussed in IPP's coal study (referenced above) this trend is expected to continue as higher quality coal mine reserves are depleted.
>
> Because IPP must permit Unit 3 for the life of the unit, the permit application must include a reasonable estimate of the anticipated future coal characteristics. Based on a review of data from Utah mines, IPP concluded that a sulfur content of 0.75% represents a reasonably conservative estimate of future Utah coal reserves. Therefore, IPP proposed a permit limit based on controlling $SO_2$ emissions from a coal containing 0.75% sulfur."

From Figures 2 and 3 (Sargent & Lundy, Technical Memorandum, December 18, 2003), we can see that the average sulfur content increased from approximately 0.55% to 0.75% for Intermountain and from approximately 0.45% to 0.75% for Hunter. The standard deviation increased from approximately 0.25% to 0.30% and from approximately 0.05% to 0.40%, respectively. Based on all available information, we believe that a sulfur content of 0.75% is a reasonable estimate.

**Comment #22**

> "Emission estimates for sulfuric acid mist appear inconsistent between IPP Units 1, 2 and 3." (EPA, p.7)

Response

The average **actual** $H_2SO_4$ emissions for Units #1 & #2 over the 2-year baseline period was 0.49 lb/hr. The **estimated** $H_2SO_4$ emissions for Unit #3 were calculated as 39.7 lb/hr based on conservative but commonly accepted assumptions. These assumptions are: 1% of the flue gas $SO_2$ will oxidize to $SO_3$ in the boiler, 1.2% will convert across the SCR and the overall $H_2SO_4$ removal efficiency of the fabric filter and the WFGD will be 90%.

**Comment #23**

> "The Approval Order must also specify a required $SO_2$ removal efficiency." (UWG, p.27)

Response

The comment is incorrect. Pursuant to R307-101-2, "BACT" is defined as "an emission limitation" that is "based on" the maximum degree of reductions in emissions. Accordingly, UDAQ has established two emission limitations representing BACT for $SO_2$ emissions from Unit #3. There is nothing in the applicable regulations to suggest that, in order to be lawful, the AO should actually specify the minimum control efficiency upon which the emission limitations are based.

See, also, the responses to Comments #19 and #20. We find that with these limits the IPP Unit 3 will not cause $SO_2$ increment violations at Capitol Reef National Park or excessive visibility impact at nearby Class I areas. (See also our response to Comments #68 and #69 for a more detailed discussion of these issues.) The commenter refers to an EPA Region VIII letter to the Montana Department of Environmental Quality regarding the Roundup Power Plant PSD permit (December 18, 2002). We quote from this letter (emphasis added):

> "BACT in terms of control efficiency. A minimum required $SO_2$ scrubber efficiency should be included in the permit, to ensure proper operation and maintenance of the scrubber, and to ensure that $SO_2$ emissions are minimized at all times, regardless of the sulfur content in the coal. **Because of the severe visibility impacts** identified by the Federal Land Managers, we believe the permit should specify scrubber efficiency in the range of 94% to 96% …."

The reason for this comment appears to be "the severe visibility impacts" of the Roundup Power Plant. That is not the case for the IPP Unit 3.

**Comment #24**

> "IPP Unit 3 must be designed with sufficient capacity in its $SO_2$ controls such that no bypass will occur." (UWG, p.27)

Response

To the extent that the comment suggests that the AO, in order to be lawful, must include an equipment design or work practice requirement in addition to the limits on the $SO_2$ emission rate, the comment is incorrect. Pursuant to R307-101-2, "BACT" is defined primarily as an emission limitation and UDAQ has established two emission limitations representing BACT for $SO_2$ from Unit #3. An additional equipment design requirement would be redundant and unnecessary.

However, as a note, UDAQ finds that the IPP Unit 3 is being designed such that no bypass of the WFGD will occur under either normal or extraordinary operating conditions.

**Comment #25**

"The planned $NO_x$ control systems can achieve lower emission rates." (UWG, p.28)

Response

UDAQ has reconsidered the $NO_x$ emission limit in light of the additional information provided by the commenters. However, we find that the $NO_x$ emission limit was properly set at 0.07 lb/MMBtu on a 30-day average. At this point in time, this is the most stringent $NO_x$ limit, that we are aware of, imposed by any permit, granted or pending, on pulverized coal-fired boilers in the U.S.A.

Each of the documents cited by the commenter provides information on design control efficiency levels or other similar values; none presents any data indicting that a $NO_x$ emission limitation more stringent than 0.07 lb/MMBtu on a 30-day average has been demonstrated to be achievable continuously. Thus, these documents are of no value in the BACT analysis except for general information.

**Comment #26**

"$NO_x$ Control" (NPS, p.4)

Response

The permit applications cited by the commenter are for facilities that do not currently, and may not ever, exist. Neither permit application presents any data indicating that a $NO_x$ emission limitation more stringent than 0.07 lb/MMBtu on a 30-day average has been demonstrated to be achievable continuously. Thus these documents are of no value in the BACT analysis except for general information. See, also, the response to Comment #25 above.

The $NO_x$ emission limit of 0.07 lb/MMBtu for a 30-day averaging period is part of the BACT analysis. However, the emission limit of 633.5 lb/hr for 24-hour averaging period is provided for NAAQS, PSD increments, and Nonattainment Area impacts. It is enforceable and consistent with the BACT emission limit for a 30-day averaging period but it is not a result of the BACT analysis.

**Comment #27**

"The $NO_x$ BACT limit must apply on a 24-hour basis." (UWG, p.29)

Response

The comment is incorrect. There is nothing in the applicable regulations indicating that the averaging period for the BACT emission limitations must be consistent with the averaging period for emission rates used in the visibility impacts analysis. The permit includes an enforceable NOx emission limitation, expressed on a 24-hour average basis, reflecting the emission rate used in the visibility impacts analysis.

This is consistent with the EPA memo of November 24, 1986, cited by the commenter. We quote (emphasis added):

> "In the case of sulfur dioxide (SO2), source compliance with the 30-day rolling average emission limit under subpart D(a) does not adequately demonstrate compliance with the short-term NAAQS and PSD increments. Consequently, **enforceable** limits pertaining to the performance of the flue gas desulfurization system on a short-term basis must also be established. Note, however, that the **short-term limits can result from either BACT analysis or the need to protect air quality**."

See, also, the response to Comment #26 above.

**Comment #28**

> "The $PM_{10}$ limit is not reflective of the maximum reductions achievable." (UWG, p.29)

Response

UDAQ has reconsidered both the filterable $PM_{10}$ and the total filterable PM emission limits in light of the additional information provided by commenters. We have also requested and obtained additional information from IPP. Based on all additional information, UDAQ has established more stringent $PM_{10}$ emission limits on the IPP Unit 3. The following limits will be in the AO:

0.012 lb/MMBtu for the filterable $PM_{10}$ and
0.013 lb/MMBtu for the total filterable PM.

These are the most stringent filterable $PM_{10}$ and total filterable PM emission limits, that we are aware of at this point in time, imposed by any permit, granted or pending, for pulverized coal-fired boilers in the U.S.A.

**Comment #29**

> "PM Control" (NPS, p.4)

Response

See the response to Comment #28 above.

The commenter quotes the emission limit of 0.0088 lb/MMBtu for the Northampton Generating station. The Northampton facility is a circulating fluidized-bed boiler burning anthracite culms; it is not a similar source burning similar fuel. Two cyclones return a very high percentage of fly-ash and unburned carbon to the furnace. Emissions of PM are further controlled by fabric filters. The same control technology is proposed for the IPP Unit 3.

The total $PM_{10}$ value of 221 lb/hr, filterable and condensable, is provided for NAAQS, PSD increments, and Nonattainment Area impacts; it is not a result of the BACT analysis. We have selected the most stringent limit of 0.012 lb/MMBtu for the filterable $PM_{10}$. The condensable $PM_{10}$ limit, calculated from the BACT/MACT emission limits for $H_2SO_4$, HCL and HF, is 0.009 lb/MMBtu. Based on all available information, UDAQ finds that these limits are appropriate.

The statements made in the paper cited by the commenter are opinions and not commercial offers backed-up by guaranties. Thus, they are not properly part of BACT analysis except for general information.

**Comment #30**

"BACT for filterable $PM_{10}$ should be more stringent." (EPA, p.2)

Response

Please see the response to Comments #28 and #29.

**Comment #31**

"BACT emission limits for total $PM_{10}$, CO and $NO_x$ should be in lb/MMBtu, not just lb/hr." (EPA, p.3)

Response

UDAQ has considered this comment and found the following:

- The CO emission limit on a 30-day rolling average is indeed a BACT emission limit and should be provided in lb/MMBtu. The appropriate value of 0.15 lb/MMBtu will be in the AO.
- The filterable and condensable PM10 emission limit on a 24-hour block average, the CO emission limit on an 8-hour rolling average, and the NOx- emission limit on a 24-hour block average are provided for NAAQS, PSD increments, and Nonattainment Area impacts; the values are appropriately given in lb/hr.

We have also reviewed the recent permits for coal-fired boilers and found that this is the common practice. The BACT emission limits are given in lb/MMBtu and the emission limits for NAAQS, PSD increments, and Nonattainment Area impacts are usually given in lb/hr.

**Comment #32**

Continuous Emission Monitor for $PM_{10}$. (NPS, p.8 and EPA, p.7)

Response

UDAQ has reconsidered the issue of PM CEMS in light of the additional information provided by the commenters. We have also requested and obtained additional information from IPP and others. Based on all available information, UDAQ believes that PM CEMS are still not advanced enough to provide reliable and accurate data at a reasonable cost. Regardless, UDAQ conducted further inquiry into this issue by contacting three sources that were represented as having working CEMs. These sources, Tampa Electric, Virginia Electric Power and Eli Lilly Pharmaceutical, were each contacted with the following general responses: Tampa Electric indicated that they had submitted a report to the EPA that essentially said that the CEM they had been using for the past two years did **not** meet the requirements of PS-11. The Florida DEP and Region IV indicated that they had not yet reviewed the report; EPA's OAQPS is currently reviewing the report and while there is indication from some that they disagree with the conclusions of the report, a response has not been issued. Virginia Electric Power indicated that they were required to install a CEM device as the result of a consent order but were unsure how they would be able to comply. They did intend to put two separate and redundant units on each of their two stacks (one a wet stack and one a dry) because they were not confident in the reliability of the CEM. Eli Lilly indicated that they had a working device from Switzerland that worked rather successfully for their specific application (i.e., narrow particle size distribution, non-variable flow rate, etc.); there is considerable concern that due to the broader size distribution of the PM and the variable flow rate that this unit would not be appropriate for IPP – a device of this type has not been used in this type of application before. As stated above, UDAQ believes that, at the current time, PM CEMS are neither reliable nor accurate for the specific circumstances that this approval order is addressing. Additional discussion is available in the IPP response to this comment and the letter of June 9, 2004 from Deseret Power to EPA-Region 8.

**Comment #33**

> "UDAQ must include a visible emissions standard reflective of BACT." (UWG, p.30)

Response

UDAQ included visible emissions standards in the ITA: for all the baghouse stacks 10% opacity and for all the other points 20% opacity. These standards will be in the AO. In addition, a visible emissions standard reflective of BACT for the main boiler stack of 10% opacity will be included in the AO.

**Comment #34**

> "UDAQ did not properly analyze the cost effectiveness of use of a wet ESP to achieve a lower sulfuric acid mist emission rate." (UWG, p.31)

Response

UDAQ found that the technical feasibility of a wet ESP for control of $H_2SO_4$ emissions for IPP Unit #3 is questionable (see the Modified Source Plan Review pages 113 to 120). However, we have reconsidered the cost effectiveness of the wet ESP in light of the comment. The average cost effectiveness of a fabric filter (FF) and a wet FGD (WFGD), calculated as suggested by the commenter is $904 per ton of $H_2SO_4$ emissions removed (based on 1,610 tons/yr removed). The average cost effectiveness of the wet ESP plus the FF and the WFGD is $8,938 per ton of $H_2SO_4$ emissions removed (based on 1,749 tons/yr removed). The cost for each control option (FF + WFGD & WESP + FF + WFGD) is $1,455,440 and $15,632,562 per year, respectively. The incremental cost effectiveness of going from the FF and WFGD to the use of the wet ESP plus the FF and WFGD is thus $101,994 per ton removed [($15,632,562 - $1,455,440) ÷ (1,749 tpy – 1,610 tpy)] for the additional 139 tons/yr removed. UDAQ found that the wet ESP is not only technically questionable but is cost prohibitive as well. Furthermore, the impact on visibility from the $H_2SO_4$ emissions controlled by the FF and the WFGD without the WESP is only about 2% and will not cause an adverse impact on visibility. No perceptible impact on stack opacity is expected either at the $H_2SO_4$ concentration of 1.5 ppmdv (without the wet ESP) or less expected at the stack.

**Comment #35**

> "BACT emission limits must apply at all times, including periods of startup, shutdown and malfunction." (EPA, p.3 and UWG, p.32)

Response

UDAQ has reconsidered the issue in light of the comments. The BACT emission limits for IPP Unit 3 will be restated in the AO.

**Comment #36**

> "Explanation needed on how discussion of case-specific MACT determination led to the mercury emission limit proposed in the ITA." (EPA, p.5)

Response

The discussion of "Case-by-case MACT for Mercury" on pages 138 to 151 of the "UDAQ Modified Source Plan Review" is based on the best level of mercury control achieved in practice by similar utility scale PC-fired boilers burning western bituminous coals. However, UDAQ decided to use the more stringent emission limit proposed by EPA (69 FR 4720 Jan 30, 2004) as indicated on pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review". UDAQ accepted the EPA conclusion on the best level of mercury control achieved in practice by similar utility scale boilers burning bituminous coals; thus, limiting to PC-fired boilers and western bituminous coals was not accepted. The EPA approach resulted in a wider pool of similar boilers and a more stringent emission limit. UDAQ believes that this emission limit is achievable in practice.

The requirement in 40 CFR 63.43(d)(1) that the limit "not be less stringent than the emission control which is achieved in practice by the best controlled similar source , as determined by the permitting authority" is satisfied as demonstrated by reference to the EPA proposed rule (69 FR 4666 & 4678 Jan 30, 2004) and the related background documents in the EPA dockets (Docket ID No.OAR-2002-0056 and Docket ID No.A-92-55).

**Comment #37**

> "Case-specific MACT determination for mercury should be expressed as an emission limit rather than just "a rate"." (EPA, p.5)

Response

We agree with EPA that the header in Condition 12 of the ITA should be re-titled "limit".

**Comment #38**

> "UDAQ failed to impose an enforceable mercury emission limitation as MACT." (UWG, p.36)

Response

See the response to Comment #36 above.

UDAQ properly proposed an enforceable mercury emission limit in the ITA (Condition 12), as discussed on pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review". We did not propose using $SO_2$ and PM emission limits as surrogates for meeting the mercury limit.

UDAQ included testing, monitoring, record keeping and reporting requirements consistent with 40 CFR §63.43(g)(2) and 40 CFR §70.6(c) and, by reference, with the EPA proposed rule (69 FR 4652 Jan 30, 2004). See pages 151, 152 and 164 of the "UDAQ Modified Source Plan Review" and Condition 12 of the ITA.

An enforceable mercury emission limit as well as appropriate testing, monitoring, record keeping and reporting requirements will also be included in the AO.

**Comment #39**

> "The ITA fails to ensure compliance with case-by-case MACT requirements." (UWG, p.32)

Response

See the response to Comments #36, #40, and #41.

**Comment #40**

> "UDAQ failed to adequately determine the level of mercury control achieved by the best controlled similar source." (UWG, p.33)

Response

Please see the response to Comment #36.

We agree with the commenter that effective mercury controls are available for all coal-fired utility boilers; however, their efficiencies depend on the type of coal burned. This conclusion is amply supported by data. Please see the EPA proposed rule (69 FR 4666 Jan 30, 2004) and the related background documents in the EPA dockets (Docket ID No.OAR-2002-0056 and Docket ID No.A-92-55) (emphasis added):

> *"The EPA found that each of the best-performing units had a combination of factors that was the basis for the better performance on that particular unit. The factors identified included the* ***Hg and chlorine (Cl)*** *contents of the coal, the* ***speciation of the Hg*** *in the flue gas stream, and the control device configuration."*

The mercury emission speciation testing, for example, revealed that the particulate-bound mercury percentages were greatly dependent on coal rank. The averages were:

| | |
|---|---|
| Bituminous coal | 44.49% |
| Subbituminous coal | 22.97% |
| Lignite | 17.09% |
| Coal refuse | 99.31% |

The particulate-bound mercury is efficiently removed in some control devices such as fabric filters. Thus, their efficiencies depend greatly on coal rank.

The Kline Township Cogen boiler, referred to by the commenter, burns coal refuse. It does not belong to the subcategory of bituminous coal-fired units by the EPA proposed rule. We believe that this subcategorization is justified as elaborated above. Thus, the Kline Township Cogen boiler was not considered. We mention though that the particulate-bound mercury percentage measured for this unit was 99.02%.This explains the high efficiency of the fabric filters installed at the Kline Township facility.

The Mecklenburg Cogeneration facility, also referred to by the commenter, has an average emission rate of 0.1062 lb/TBtu. However, the 97.5th percentile emission limit for this facility, when an appropriate variability is added, is 1.8051 lb/TBtu. We prescribed a more stringent emission limit of 0.6094 lb/TBtu i.e. $6.0x10^{-6}$/MWh.

**Comment #41**

> "UDAQ failed to evaluate and prescribe a mercury emission limitation reflective of the maximum degree of reduction in emissions of mercury that could be achieved." (UWG, p.37)

Response

UDAQ properly evaluated and prescribed a mercury emission limitation reflective of the maximum degree of reduction in emission of mercury that could be achieved taking into consideration the costs; this is referred to as MACT beyond-the-floor.

Based upon available information, as defined in 40 CFR §63.41, UDAQ found that such beyond-the-floor control technologies are not available and demonstrated. In this, UDAQ agrees with the EPA proposed rule (69 FR 4679 &4698 Jan 30, 2004):

> *"Once the MACT floor determinations were done for new units in each subcategory (by fuel type), EPA considered various regulatory options more stringent than the MACT floor level of control (i.e., additional technologies or work practices that could result in lower emissions) for the different subcategories. Due to the technical complexities of controlling metal HAP emissions from the sources affected by this rule, however, EPA has not been able to determine whether identified potential beyond-the-floor options are available and demonstrated.*
>
> *Research currently indicates that Hg control technologies other than FGD and SCR--most notably activated carbon injection (ACI) and breakthrough technologies (e.g., chemical systems to enhance removal efficiencies for wet scrubbers)--may one day allow facilities to reliably reduce Hg emissions to levels significantly below the levels achieved through application of FGD and SCR needed to satisfy SO2 and NOX control requirements. However, these technologies have not been adequately demonstrated on full-scale power plants."*

UDAQ identified and considered all potentially available control technologies. We did not find any such technology that we would consider actually available as a MACT beyond-the-floor, defined in 40 CFR §63.43(d)(2). The most promising one, activated carbon injection, is discussed in the "UDAQ Modified Source Plan Review".

**Comment #42**

> "UDAQ did not evaluate inherently lower emitting processes." (UWG, p.39)

Response

UDAQ did not find any inherently lower emitting process that is available. The commenter is specifically proposing IGCC. See also the response to Comment #12 above. However, IGCC is not a similar source to other coal-fired facilities as defined in 40 CFR **§**63.41 (emphasis added):

> *"Similar source means a stationary source or process that has comparable emissions and is **structurally similar in design and capacity** to a constructed or reconstructed major source such that the source could be controlled using the same control technology."*

The EPA proposed rule also finds that IGCC is a unique process different from other coal-fired processes (69 FR 4666 Jan 30, 2004):

> *"For the purposes of the proposed rule and based on the above information, the coal-fired units at existing affected sources are subcategorized into five subcategories, four based on coal rank and one based on process type: bituminous (including anthracite); subbituminous; lignite; coal refuse (which includes anthracite coal refuse (culm), bituminous coal refuse (gob), and subbituminous coal refuse); and IGCC (coal syngas).*
>
> *Integrated gasification combined cycle units combust a synthetic coal gas. No coal is directly combusted in the unit during operation (although a coal-derived fuel is fired), and, thus, IGCC units are a distinct class or type of boiler for the proposed rule."*

Therefore, IGCC facilities were not included in the pool of similar sources when determining the mercury MACT floor by 40 CFR §63.43(d)(1).

That IGCC is not a control technology is also generally understood. Thus, IGCC facilities were not included in the pool of control technologies potentially available for the mercury MACT beyond-the-floor.

**Comment #43**

> "Use of sorbent injection for mercury control should have been thoroughly evaluated." (UWG, p.39)

Response

UDAQ thoroughly evaluated use of sorbent injection, such as activated carbon, for mercury control. We considered activated carbon injection on pages 138 and 142 and on page 152 by reference to the EPA proposed rule. The following quotes are from the EPA proposed rule (69 FR 4676&4673 Jan 30, 2004):

> *" Although AC, chemically-impregnated AC, and other sorbents show potential for improving Hg removal by conventional PM and SO2 controls, this technology is not currently available on a commercial basis and has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (e.g., longer than a few days) data are available to indicate the performance of this technology on all representative coal ranks or on a significant number of different power plant configurations. Therefore, we do not believe these technologies provide a viable basis for going beyond-the-floor.*
>
> *Some have argued that the experience gained from regulation of Municipal Waste Combustors and Health, Medical and Infectious Waste Incinerators in the early 1990s indicates that coal-fired power plants should be able to achieve 90*

*percent Hg emission reductions (see ``Out of Control and Close to Home: Mercury Pollution from Power Plants.'' Environmental Defense. 2003). The EPA expects that some Utility Units can achieve such high reduction rates, depending on factors such as the Hg and Cl content of different coals, as outlined above. However, there are important technical differences between Utility Units and municipal waste combustors and health, medical and infectious waste incinerators. Consequently, EPA believes 90 percent emission reductions cannot be achieved across all Utility Units in the proposed section 112 time frame.”*

Regarding the referenced MidAmerican facility**,** there are several significant facts that must be considered:

- The coal to be burned is subbituminous;
- The expected control efficiency without activated carbon injection is only 34%;
- The expected control efficiency even with activated carbon injection is still only 70% or 83%, depending on interpretation;
- The Iowa Department of Natural Resources (IDNR) imposed a mercury emission limit of 1.7 lb/TBtu i.e. 16.7 x 10-6 lb/MWh.

UDAQ, on the other hand accepted the EPA proposed rule; the best controlled source is the Stockton facility:

- Bituminous coal is burned;
- The measured control efficiency without activated carbon is 92%;
- Activated carbon injection is not installed;
- A 97.5th percentile emission limit is 0.61 lb/TBtu i.e. 6.0 x 10-6 lb/MWh.

Additionally, both MidAmerican and IDNR consider activated carbon injection experimental as evidenced from their comment and response (IDNR Response to Public Comments, July 17, 2003, pages 6 and 7).

MidAmerican comment:

> “However, because a PAC system is still considered experimental for achieving mercury reductions, MidAmerican believe it is appropriate that testing and optimization of the system define the final emission limit for mercury.”

IDNR response:

> “This limit will be reviewed along with the results of the optimization study as noted in condition 14.M.(6).”

The commenter also states:

> “Indeed, the website of the company that performed all of the full-scale studies of sorbent injection at coal-fired power plants, ADA-ES, indicates that sorbent injection is “proven technology’ that “works for all coal plants and configurations,” is “cost effective” and “available now”.”

This statement means nothing beyond the fact that this technology is available for sale. It does not show that this control technology is available in the sense of 40 CFR **§**63.43(d)(2) i.e. with acceptable cost and risk.

In addition, the cost analysis presented in this comment overlooks an important aspect: the risk involved in installing a control technology that “*has not been installed, except on a demonstration basis, on any electric utility unit in the U.S. to date. Further, no long-term (e.g., longer than a few days) data are available to indicate the performance of this technology on all representative coal* *ranks or on a significant number of different power plant configurations*" (69 FR 4676 Jan 30, 2004).

In summary, UDAQ thoroughly evaluated sorbent injection as an option for controlling mercury to the maximum extent at IPP Unit 3. "Additional cooling" was only one of the reasons for dismissing activated carbon injection, as demonstrated above. UDAQ prescribed a substantially more stringent emission limit proposed by EPA of 0.61 lb/TBtu i.e. $6.0 \times 10^{-6}$ lb/MWh.

**Comment #44**

> "UDAQ should have evaluated use of K-fuels at IPP unit 3." (UWG, p.41)

Response

See the response to Comment #17. UDAQ evaluated the use of K-fuels at IPP unit 3 by reference to the EPA proposed rule. The following quotes are from the EPA proposed rule (69 FR 4677 & 4678 Jan 30, 2004):

> *"As was the case for existing units, in developing a MACT strategy for new units, EPA considered several prevention measures as an alternative to the application of Hg and Ni control technology. These measures were the same precombustion techniques evaluated for existing units, which included fuel substitution, process changes, and work practices.*
>
> *For these reasons, EPA decided that mandated fuel type is not an appropriate criterion for identifying the MACT level of control for new coal-fired units. In any event, we do not believe that we can or should prescribe a given fuel type because of the implications on electricity reliability, energy security, etc."*

Other mercury control technologies such as electro catalytic oxidation and advanced dry FGD all have limited commercial experience on coal-fired utility boilers. UDAQ does not consider them available for the mercury MACT beyond-the-floor.

**Comment #45**

> "UDAQ failed to meet the case-by-case MACT requirements for other HAPs." (UWG, p.42)

Response

UDAQ met all of the case-by-case MACT requirements for other HAPs to be emitted by IPP Unit 3. In particular, UDAQ set the MACT floor; we also considered MACT beyond-the-floor; and we set enforceable emission limitations for mercury. However, we, like EPA, decided not to promulgate standards for emissions of non-mercury pollutants (69 FR 4656&4659 Jan 30, 2004):

> *"As for the other non-Hg and non-Ni metallic HAP examined, EPA made the following conclusions. With regard to arsenic, a metal, EPA concluded that there were several uncertainties associated with both the cancer risk estimates from arsenic and the health effects data for arsenic, and that further analyses were needed to characterize the risks posed by arsenic emissions from Utility Units*

*(ES at 21). As to lead and cadmium, which are also metals, EPA found that the emission quantities and inhalation risks of these HAP were low and did not warrant further evaluation (ES at 24).* ***As for the remaining, non-Hg, non-Ni metallic HAP, EPA found that such pollutants posed no hazards to public health.***

*The EPA also examined HCl and HF, which are inorganic or acid gas HAP, and found* ***no exceedances of the health benchmark for either substance*** *(ES at 24). As for dioxins, organic HAP, EPA concluded that the quantitative exposure and risk results for such* HAP "**d*(id) not conclusively demonstrate the existence of health risks of concern associated with exposures to utility emissions either on a national scale or from any actual individual*** **utility.**" *(Utility RTC at 11-5.) Finally, EPA concluded that emissions from Utility Units of* ***the remaining HAP examined in the Study did not appear to be a concern for public health*** *(65 FR 79827).*

*In the circumstances presented here, and as discussed below, EPA interprets section 112(n)(1)(A) only to authorize the Agency to promulgate section 112 standards for Utility Units with respect to HAP emissions from such units that are reasonably anticipated to result in a hazard to public health after imposition of the other requirements of the CAA. To the extent section 112 can be interpreted as authorizing but not requiring EPA to go beyond that, and to promulgate section 112 standards for HAP emissions that are not reasonably anticipated to result in a hazard to public health, EPA has decided not to do so."*

UDAQ also looked at a different approach based on 40 CFR **§**63.43(d)(3):

*"The applicant may recommend a specific design, equipment, work practice, or operational standard, or a combination thereof, and the permitting authority may approve such a standard if the permitting authority specifically determines that it is* ***not feasible*** *to prescribe or enforce an emission limitation under the criteria set forth in section 112(h)(2) of the Act.*
*[****112(h)(2) Definition.*** *— For the purpose of this subsection, the phrase "not feasible to prescribe or enforce an emission standard' means any situation in which the Administrator determines that—... (B) the application of measurement methodology to a particular class of sources is not practicable* ***due to technological and economic limitations****.] "*

UDAQ found that it was not practical to impose emission limits directly due to technological and economic limitations of measurement methodology. A practical alternative is the use of surrogates (State and Local Air Pollution Control Officials Recommendations for Utility MACT Standards, Utility MACT Workgroup Meeting, October 22, 2002):

"One practical way to address the large number of non-mercury HAPs emitted by coal-fired boilers is through the use of surrogates. Surrogates may be non-HAPs ( for example, CO or PM2.5 mass) or a single HAP that is representative of many HAPs. This approach is useful to efficiently and effectively address the majority of HAPs emitted by coal-fired plants.

A surrogate is useful if efforts to minimize the surrogate also result in the minimization of a group of HAPS which have common air pollution control

> properties. Under section 112(d) of the CAA, the Administrator is directed to use emission information to set MACT limits. The Administrator is not limited to using only HAP emission information, and it is reasonable to conclude the Administrator may also use information on other emissions which are associated with HAPs emissions. A surrogate is particularly useful if it can be continuously monitored and serve as a continuous indicator of HAP emissions."

Precedent was provided by EPA in establishing MACT standards for several categories of sources emitting non-mercury HAP metals (66 FR 36835, July 13, 2001):

> *"For the proposed rule, we decided that it is not practical to establish individual standards for each specific type of metallic HAP that could be present in the various processes (e.g., separate standards for manganese emissions, separate standards for lead emissions, and so forth for each of the metals listed as HAP and potentially could be present). When released, each of the metallic HAP compounds behaves as PM. As a result, strong correlation exists between air emissions of PM and emissions of the individual metallic HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions. Therefore, we decided to establish standards for total PM as a surrogate pollutant for the individual types of metallic HAP. In addition, establishing separate standards for each individual type of metallic HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach based on total PM."*

This approach was considered for the IPP Unit 3 on pages 136 to 140 and page 151 of the "UDAQ Modified Source Plan Review". The BACT emission limits for surrogate pollutants, PM, $SO_2$, and CO, were shown to be the appropriate MACT emission limits for non-mercury HAPs. The enforceable emission limitations were formulated on page 151 through the emission limitations of the surrogate pollutants. However, UDAQ, like EPA, decided not to promulgate standards for emissions of non-mercury pollutants.

**Comment #46**

> "Reducing Emissions from IPP Units 1 and 2" (NPS, p.14)

Response

UDAQ welcomes NPS suggestions and support. However, this issue is not part of the present project out for comment.

**Comment #47**

> "We strongly support UDAQ in using differential pressure as a permit condition due to the fact that we have shown that the use of differential pressure is equivalent to a grain loading method of determining emissions and we appreciate the flexibility that UDAQ is extending here." (IPSC/IPA, p.3)

Response

The comment was noted. As no technical issue was raised with respect to the ITA, no changes were made to the AO.

**Comment #48**

> "The mercury emission rate in Condition 12 is $6.0x10^{-6}$ lb/MMBtu. This number should reflect the complete proposed MACT rate for mixed blends of bituminous ($6x10^{-6}$ lb/MWh) and subbituminous coals ($20x10^{-6}$ lb/MWh). Please revise this mercury limit to range between $6x10^{-6}$ lb/MWh and $20x10^{-6}$ lb/MWh proportional to the fuel blend ratio to allow us to burn this range of coals. The MACT utilizes a calculation based upon the blend ratio." (IPSC/IPA, p.3)

Response

The AO will include the appropriate statement to reflect the proposed MACT rule for mercury.

**Comment #49**

> "The opacity limit of 20% for fugitive dust sources is not required under any state requirement, and the fugitive dust control plan required in Condition 16 should be the basis for BACT. Please remove the second paragraph of Condition 16 with 20% opacity limit." (IPSC/IPA, p.3)

Response

The opacity limit of 20% for visible fugitive dust emissions from haul-road traffic and mobile equipment is the result of the BACT analysis. No changes were made to the AO.

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DAQP-085-04

## MEMORANDUM

**TO:** Intermountain Power Service Corporation (IPSC) File (N327010)

**THROUGH:** Cheryl Heying, Manager, Planning Branch CH

**THROUGH:** Brock LeBaron, Manager, Technical Analysis Section BL

**FROM:** Tom Orth, Air Quality Modeler

**DATE:** October 15, 2004

**SUBJECT:** Technical Analysis' response to comments received on IPSC's Intent to Approve number DAQE-IN327010-04

On April 1, 2004, a public comment period began to solicit comments on the Intent to Approve (ITA) Intermountain Power Service, Corporation's (IPSC) addition of a new Unit 3 at their existing Intermountain Power Plant (IPP), located in Delta, Millard County, Utah.

Numerous comments were received during the comment period and at the public hearing. All comments received during the public hearing and the two public comment periods pertaining to the Air Quality Impact Analysis (AQIA) are listed here, with the original comments being included as an attachment. Following each comment is the Utah Division of Air Quality's (UDAQ) response, along with any action taken by the Division in regards to the final Approval Order (AO).

Quoted items are taken verbatim from the original comment submission. If the comment was unclear, UDAQ attempted to explain the comment as understood by the Division. Public comments addressed in this document represent a paraphrasing of the originally submitted comment. Readers should refer to the attached original comments for the full text of the comment.

The UDAQ responded to the attached comments made during the public comment periods (PCP) from April 1, 2004 to May 21, 2004, from June 3, 2004 to July 3, 2004, and the public hearing of April 29, 2004.

TO/gw

Attachment

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**<u>Responses to EPA's May 24, 2004, comment letter on the addition of IPP - Unit 3</u>**

**Comment 1: Short-term Emission Rate (pg 5, p3)**

Maximum short-term emission rates should be used in modeling for consumption of short-term PSD increment. The PSD Class I increment analysis does not appear to have included appropriate emission rates from increment consuming sources in the area and as a result, cumulative increment consumption in the Class 1 areas may have been underestimated.

**Response:**

The EPA suggests that the Acid Rain Continuous Emissions Monitoring (CEM) data might be appropriate to use in an increment analysis. UDAQ examined this possibility during the initial review of the permit application and found it to be troubling. Increment consumption for existing sources should be based on actual changes in emissions since the baseline date. CEM data includes the substitution of artificially inflated maximum hourly emission rate for periods when the CEM was offline, in order to meet the requirements of the Acid Rain emissions credit portion of the program. If, as EPA has suggested, actual short-term CEM data were to be used in the analysis, hourly emission should then be paired in time and space with actual hourly weather data to verify that the increment violation would likely have occurred.

At the time IPA established its Class I and AQRV modeling methodology with the NPS and UDAQ, the 1996 MM5 data set was the acceptable meteorological data set for modeling Class I and AQRV impact in the US. This one-year data set met IPA's legal requirement for long-range transport modeling at the time the methodology was developed. PSD modeling guidance further requires that estimates of actual emissions for existing sources be based on the most current two-year period representing normal operations at the facility. In the case of IPP, that period was 2000 through 2001. Since the emissions data could not be paired in time and space with the meteorology, the UDAQ elected to allow the use of an emission methodology that better represented normal operations at the facilities, and would result in concentration estimates in the Class I areas that had a higher statistical probability of actually occurring. The UDAQ believes that the increment consumption methodology used in the analysis meets the requirements of the Clean Air Act, and that no further Class I increment modeling for this permit action is warranted.

**Comment 2: Meteorological Data (pg 6, p4)**

IPP's modeling analysis included only one year (1996) of prognostic meteorological data. If the State is "grandfathering" the previous 1-year data requirement for this source, the basis for it should be stated.

**Response:**

The UDAQ did not "grandfather" the data requirement; it followed applicable rules. On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the previous requirement for one year of mesoscale meteorological (MM5) data to simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective data for the three-year meteorological data requirement April 15, 2004. The IPA modeling was considered complete before the April 15, 2004 deadline passed. Conversations with EPA Region VIII meteorologist, Kevin Golden, confirmed their policy that the uses of the most current guidance requirements have practical limitations. A permitting source should not have to model two additional years if the original analysis has been performed, and found to be complete before the effective date of the rule. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete.

**Comment 3: Modeling Data Archives (pg 6, p5)**

There have been revisions to the project that may not be reflected in the modeling archives. Any updates or revisions to the modeling that have already been made, or will be made in response to comments, should be provided to EPA.

**Response:**

The UDAQ submitted additional modeling files as they were received.

**Comment 4: Overlapping Energy Projects (pg 6, 6)**

EPA recommends an analysis of any potentially overlapping ambient impacts of the large energy projects in Utah for which permits are simultaneously pending. This includes NEVCO, and PacifiCorp - Currant Creek.

**Response:**

The two above-mentioned energy projects were not required to be included in the IPP analysis at the time the modeling protocol was approved since their applications were not complete at that time. In addition, since NEVCO and Currant Creek's impacts on all Class I areas are below the Class I SIL for all pollutants, it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects that have submitted applications since the modeling for IPP was approved by the UDAQ.

**<u>Responses to NPS's May 27, 2004 comment letter on the addition of IPP - Unit 3</u>**

**Comment 1: 3-Hour $SO_2$ Limit (pg 8, p3)**

We recommend that the UDAQ also include a 3-hour SO2 limit in the ITA.

**Response:**

The UDAQ is including a 3-hour $SO_2$ limit in the final AO.

**Comment 2: Short-term Emission rates (pg 8, p4)**

Based on EPA guidance, to help ensure compliance with short-term increments, the highest actual 3-hour or 24-hr average emissions during the last two years of operation should apply to the 12 other sources in this analysis. See also the response to the Environmental Groups' Comments #19.

**Response:**

The UDAQ policy for determining short-term emission rates for PSD increment consumption is to use annual average emissions divided by hours of operation. This is used for all emissions sources that are constructed and currently operating.

**Comment 3: Increment Status of PacifiCorp – Hunter Unit 1 (pg 9, p3)**

IPA did not include Hunter Unit#1 in its increment inventory.

**Response:**

The UDAQ does not interpret Hunter Unit 1 as consuming increment, since the unit has not been modified since the Major source baseline date and was in operation at the time the baseline concentration was established (i.e. major source baseline date).

**Comment 4: Inclusion of Other Energy Projects (pg 9, p3)**

Emissions from the recently permitted NEVCO Sevier draft permit are not included in the IPA cumulative increment analysis.

**Response:**

The UDAQ did not require that NEVCO be included in the IPP analysis at the time the modeling protocol was approved since the NEVCO application was not complete at that time. In addition, since NEVCO's impacts on all Class I areas are below the Class I SIL for all pollutants, it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects, which have submitted applications since the modeling for IPP was approved by the UDAQ.

**Comment 5: Ammonia Monitoring (pg 12, p2, and pg 2 of cover letter)**

We recommend that Utah collect ambient ammonia data or ask that permit applicants contribute to monitoring so that future modeling can better account for this variable.

**Response:**

Ammonia is not a federally regulated air contaminant. Therefore, the UDAQ does not have the authority to require a permitting source to collect ambient ammonia data.

**Comment 6: Mitigation of Cumulative Impacts (pg 14 p 3 and pg 2 of cover letter)**

We recommend consideration of additional strategies to mitigate the cumulative emission increases and visibility impacts before issuing a permit, as a prudent approach to safeguarding Utah's outstanding visibility and night skies.

**Response:**

The UDAQ does not feel that they have the authority to require IPP to reduce emissions since the NPS has determined that IPP unit 3 does not cause an adverse impact on visibility.

**<u>Responses to NPS's March 25, 2004 comment letter on the addition of IPP - Unit 3</u>**

**Comment 1: Additional Years of Class I Impact Modeling (pg 8, p2)**

In order for the Federal Land Manager to have a more informed decision regarding IPP-3's impacts at the five Class I parks in the region, we ask that IPA run CALPUFF using meteorological data for 1990 and 1992, and report those results to us.

**Response:**

On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the previous requirement for one year of mesoscale meteorological (MM5) data to simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective data for the three-year meteorological data requirement April 15, 2004. The IPA modeling was considered complete well before the April 15, 2004 deadline passed. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete, and has no legal authority to require additional years in the analysis.

**<u>Responses to Environmental Groups' May 20, 2004 comment letter on the addition of IPP - Unit 3</u>**

**Comment 1: Cooling Tower Emissions (pg 31, p4)**

IPSC relied on a paper entitled *Calculating Realistic $PM_{10}$ Emissions from Cooling Towers*, by J. Reisman and G. Frisbie in justifying a lower $PM_{10}$ emission factor for the Unit 3 cooling tower. The emission rate is 1/3 that projected for Units 1 and 2. If Unit 3's cooling tower emissions were tripled, there would be exceedances of the PSD increment for $PM_{10}$. The Approval Order must include a $PM_{10}$ emission limitation for the Unit 3 cooling towers. The permit must also require emissions testing insures continuous compliance with the cooling tower limit.

**Response:**

The UDAQ has evaluated the affect of tripling the emission rate and has determined that the impacts from the cooling towers are in a different location than the maximum impacts from the other fugitive sources. The PSD increment would not be threatened by tripling the emission rate for the Unit 3 cooling towers. Hence, a separate emission limit for the cooling towers to protect the $PM_{10}$ increment is not warranted.

**Comment 2: Localized Soil and Vegetation Impact Analysis (pg 43, p3)**

IPSC's permit application should be denied because it failed to provide a full and complete analysis of "the impairment to visibility, soils and vegetation", and because threshold sulfate deposition rates will be exceeded in Capitol Reef National Park. *See*, 40 C.F.R. § 52.21(o)(1) & (2) and/or 40 C.F.R. §51.166. *See also*, Utah Admin. Rule R307-405-6(2)(a)(i)(D).

**Response:**

IPA presented a soils and vegetation analysis in section 8.15 of their May 15, 2003 NOI. Their analysis indicated that nitrogen impacts would be less than the 5% of the foliar injury level (see Table 8-90). There were no comments from the public that indicated that their crops were being damaged from the existing Units 1 and 2, but instead all of the comments from local farmers indicated there were no impacts.

**Comment 3: Growth Impact Analysis (pg 43, p4)**

IPSC's PSD permit application failed to provide a thorough analysis of the "general commercial, residential, industrial and other growth associated with the source" as required by 40 C.F.R. 52.21(o)(1) & (2); Utah Admin.Rule R307-405-6(2)(a)(i)(D).

**Response:**

IPA presented an analysis on the impact of "general commercial, residential, industrial and other growth associated with the source" in section 8.14 of the NOI. IPA's analysis indicated that there would not be substantial growth to the area since most of the local industry and infrastructure necessary to support the plant and is already in place. The UDAQ is in agreement with IPA's conclusion.

**Comment 4: Growth Impact Analysis (pg 43, p3)**

IPSC must evaluate the short and long term impacts associated with this growth, including any air emissions from the residential housing units (i.e. any natural gas fired appliances).

**Response:**

New emissions resulting from the addition of residential housing units (either on-site or in the nearest community of Delta, Utah) will be small, and are not regulated under Utah Air Quality Rules. In the past, the UDAQ has evaluated the environmental impact of the average residential unit, or group of units, and has determined that their impact on air quality is minimal.

**Comment 5: Growth Impact Analysis (pg 43, p3)**

There will also be increased vehicular traffic to bring the increased amount of coal to the site. The increased traffic could cause violations of the 24-hour $PM_{10}$ increment.

**Response:**

Coal for IPP Unit 3 will be hauled on site primarily using rail cars. The emissions from trains delivering coal to the plant will be quite small and were not considered in the modeling. Similarly, vehicular traffic will not be large (both delivery and on-site tail-pipe emissions) enough to impact the consumption of increment. Estimated emissions from these sources are in the 0.33 lb/hr range compared to a $PM_{10}$ limit in the AO of 221 lb/hr.

**Comment 6: Growth Impact Analysis (pg 43, p3)**

IPSC's soils and vegetation discussion is inadequate. IPSC did not evaluate impacts on soils. IPSC's vegetation analysis is limited to emissions from the stack and does not consider "general commercial, residential, industrial and other growth associated with the source" as required by 40 C.F.R. 52.21(o)(1) and Utah Admin. Rule R307-405-6(2)(a)(i)(D). Further, the vegetation analysis fails to provide a meaningful analysis of other pollutants, such as ozone, mercury, and $CO_2$.

**Response:**

Significant changes to soils and vegetation impacts near IPA are not expected to occur since the majority of impacts from sulfur dioxide and nitrogen dioxide are several kilometers away, and very low compared to the secondary NAAQS. Impacts on soil and vegetation resulting from "general commercial, residential, industrial and other growth associated with the source" are not expected to increase significantly since most of the commercial, residential, industrial and other growth necessary to support the addition of Unit 3 are already in place. The UDAQ did not find any potential adverse impacts to soils and vegetation in its review of IPA's NOI. (See section 8.15 of the NOI).

**Comment 7: Sulfur Deposition Rates (pg 44, p2)**

Sulfate deposition rates in Capitol Reef National Park will exceed the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Deposition Analysis Threshold (DAT) based on emissions from Unit 3 alone. IPSC's permit application should be denied for this reason alone.

**Response:**

The NPS did mention the exceedance of the DAT in their March 25, 2004, comment letter to the UDAQ. However, there was no mention of a finding of adverse impacts to soils and vegetation in their comments, or in their May 27, 2004, final comment letter.

**Comment 8**: **Cumulative Impacts (pg 44, p2)**

IPSC's analysis must assess the cumulative impacts to soils and vegetation, as well as deposition rates, for all three IPP Units.

**Response:**

R307-405-6(2)(a)(i)(D) states the source shall provide "an analysis of the air quality related impact of the source or modification." The rule does not require a cumulative analysis of impacts to soils and vegetation.

**Comment 9: Monitoring Requirements (pg 44, p3)**

IPSC only conducted pre-construction monitoring for the nine-month period October 2001 through June 2002, avoiding the summer period entirely.

**Response:**

IPP did conduct a full year of concurrent meteorological, $PM_{10}$, and $SO_2$ monitoring during the period from October 1, 2001 thru September 28, 2002 (see Section 8.9.1 of May 14, 2003 NOI).

**Comment 10: Cumulative Impacts (pg 44, p5)**

In the far-field $PM_{10}$ analysis, IPSC initially only analyzed the impacts from the new Unit 3. Emissions from Units 1 and 2 were not included in the analysis.

**Response:**

Utah and EPA regulations do not require the analysis of existing major sources other than the modification or new major source that is being permitted, unless the impacts from the modified source alone or new source trigger cumulative modeling requirements (i.e., Class I and II SILs). Utah County $PM_{10}$ Non-attainment area impact modeling performed by IPA correctly followed the requirement of R307-403-5(1), which states " *New sources which have a potential to emit, or modified sources which would produce an emission increase equal to or exceeding the tonnage total of combined $PM_{10}$, sulfur dioxide, and oxides of nitrogen listed below which are located in or impact a $PM_{10}$ Non-attainment Area as defined in (a) below, shall obtain an enforceable offset as defined in (b) and (c) below*." IPA was only required to model the modified part of the source (i.e., the addition of Unit 3) in their analysis.

**Comment 11: Changes to IPP Units 1 and 2 (pg 44, p5)**

As discussed in the January 23, 2004, comment letter from Grand Canyon Trust and Sierra Club to UDAQ, it appears that the increases in capacity of IPP Units 1 and 2 authorized by UDAQ in 2002 may have been in violation of Utah permitting regulations.

**Response:**

The comment addresses existing units at IPP, and does not pertain to the permitting of IPA Unit 3.

**Comment 12: Cumulative Impacts (pg 45, p3)**

(PG 45) Visibility analyses conducted by the National Park Service greatly underscore the significance of not including IPP Units 1 and 2 in the visibility impacts modeling assessment. The Park Service modeled all three units at IPP and found "numerous days with impacts greater than a 10% change in extinction at all 5 Class I parks." The March 22, 2004 Modified Source Plan Review does not include any discussion of the Park Service's visibility analyses.

**Response:**

The analysis conducted by the NPS, as stated in their May 27, 2004 comment letter for IPP Unit 3, ultimately lead to the determination by the NPS that IPP Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301)*" in any of Utah's five Class I areas. The UDAQ concurs with this determination. The Unit 3 analysis performed by the NPS showed impacts less than 5% at all parks. The Federal Land Managers' Air Quality Related Values Workgroup (FLAG) guidance document for modeling visibility impacts from new or modifying sources states that a cumulative analysis is only required if the impact from the new or modifying source exceeds 5%. A maximum change of 4.26% was predicted at Capitol Reef National Park when the 1996 MM5 data was used.

**Comment 13: Meteorological Data Requirements for Class I Analyses (pg 45, p5)**

IPSC used only one year of mesoscale meteorological data in their far field modeling assessments. However, EPA's Guideline on Air Quality Models requires that at least three years of such data be used. See Section 9.3.1.2 of 40 C.F.R. Part 51, Appendix W.

**Response:**

On April 15, 2003, the EPA published a Federal Register notice adopting revisions to the Guidelines on Air Quality Models, changing the requirement for one year of mesoscale meteorological (MM5) data to simulate long-range transport to three years of data. On May 13, 2003, EPA published a correction to this notice, making the effective date for the three-year meteorological data requirement April 15, 2004.

Additional modeling performed by IPA for the Class I CALPUFF analysis was received on a CD on June 19, 2003. Additional modeling for the Utah County CALPUFF analysis was received in July of 2003. No other modeling CDs were received after this date. The IPA modeling was considered complete well before the April 15, 2004 deadline passed. Conversations with EPA Region VIII meteorologist, Kevin Golden, confirmed their policy that the uses of the most current guidance requirements have practical limitations. A permitting source should not have to model two additional years if the original analysis has been performed, and found to be complete before the effective date of the rule. Based on this, the UDAQ feels IPA has met the legal requirements for MM5 meteorological data usage at the time the modeling was deemed complete.

**Comment 14: $PM_{10}$ Background Concentration (pg 47, p1)**

The May 2003 NOI states that the second high monitored 24-hour value for $PM_{10}$ was used to represent the background concentrations in the modeling analyses. However, no further information was given in the NOI or in UDAQ's March 22, 2004, Modified Source Plan Review regarding why the highest monitored value was not used.

**Response:**

The highest $PM_{10}$ concentration monitored during the one-year monitoring period occurred during a summertime high wind event, where windblown dust was the main contributor to the concentration. The second-highest recorded value was collected under lighter winds than the first high measurements. Lower wind speeds are conducive to high-predicted ground level impacts in the computer model. Therefore, the use of the second highest monitored value coupled with the second highest impact predicted by the model (occurring during a period of low wind speed) provided the most accurate assessment of the worst potential impact of the proposed project.

**Comment 15: Impacts on Non-Attainment Areas (pg 47, p3)**

IPSC has failed to conduct an adequate modeling analysis to determine whether IPP's impacts in the Utah County $PM_{10}$ non-attainment area would trigger the requirement for emission offsets under Utah regulation.

UDAQ should also have required modeling of all three units together to determine if the power plant will cause or contribute to $PM_{10}$ non-attainment in Utah County.

**Response:**

Additional modeling submitted by IPA in July of 2003 showed that the combined impact of $PM_{10,}$ gaseous sulfur dioxide, and gaseous nitrogen dioxide were less than the respective 24-hour and annual impact levels to require offsets, as specified in R307-403-5(1)(a). The additional analysis performed by IPA used the turbulence based dispersion option in Calpuff. This option was verbally approved by Kevin Golden before IPA performed the modeling. EPA Region VIII did not have any concerns about the use of this method as part of their comments, so the UDAQ has approved the modeling.

This rule does not require that the existing part of a facility (i.e. Units 1 and 2) be included in the model, but instead only requires that the new source or modification be included in the analysis to determine if the power plant will cause or contribute to $PM_{10}$ non-attainment in Utah County.

**Comment 16: Emission Limits during Startup, Shutdown, Malfunction, and Maintenance (pg 48, p3)**

UDAQ has proposed an exemption from all BACT emission limits for periods of startup, shutdown, malfunction, and maintenance. The air quality analysis should address these types of releases and comply with all air quality standards. The assessment also must model uncontrolled emission rates from IPP Unit 3 to address malfunctions, such as if both scrubbers were to fail.

**Response:**

The final AO will have no automatic exemptions to the limits. Utah has reviewed the issue of startup, shutdown, malfunction, and maintenance. The "exemption" that was in the ITA has been removed and the limits will apply at all times. However, since the limits (particularly NOx) are not technically achievable during periods when the SCR is not at operating temperature, language has been added to the AO that provides the opportunity for compliance discretion during those periods of startup, shutdown, or scheduled maintenance. Malfunctions will be handled in accordance with existing state rules.

**Comment 17: Class II Increment Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 49, p3)**

IPSC's startup modeling analysis submitted on July 28, 2003 (attached) shows that IPP Unit 3 *would contribute to a violation of the 24-hour average PM10 Class II PSD increments*, since Unit 3's impact with other $PM_{10}$ sources at IPP (all increment-consuming) was 37.6 μg/m$^3$, well in excess of the 30 μg/m$^3$ Class II $PM_{10}$ increment. Pursuant to Utah regulations R307-405-6(2)(a)(i)(A) and R307-405-6(2) and (c), UDAQ cannot issue an approval order in light of these Class II increment violations unless the violations are eliminated through a more restrictive emission limit or by obtaining emission offsets.

**Response:**

The UDAQ does not require new or modifying sources to demonstrate compliance with the PSD Class I and II increments during periods of startup, shutdown, malfunction, and maintenance. However, when comparing IPP's original $PM_{10}$ modeling for normal operations with the above mentioned modeling during periods of startup, shutdown, malfunction, and maintenance, it appears that approximately 8 μg/m$^3$ of the 37.6 μg/m$^3$ impact cited above, would be attributable to operations involved in bring the unit online (startup). On August 26, 2004, IPP submitted a revised $PM_{10}$ modeling analysis that included additional control strategies for fugitive emissions. Fugitive emissions account for the greatest percentage of IPP's predicted 24-hour $PM_{10}$ impact. Additional fugitive emission controls included surfactant to stabilize coal dust, chemical treatment of unpaved road, sweeping of all paved surfaces, and limitations on testing of emergency generators. IPA's AO will require the source to submit the proposed additional control measures for fugitive emissions as part of an enforceable fugitive dust control plan within 90 days of its issuance. The revised analysis showed that during normal operations the potential 24-hour $PM_{10}$ impact would be 13.4 μg/m$^3$. Adding in the additional 8 μg/m$^3$ from startup operations, the potential impact would be approximately 22 μg/m$^3$, well below the PSD 24-hour $PM_{10}$ Class II increment of 30 μg/m$^3$**.**

**Comment 18: Non-Attainment Area Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 49, p4)**

UDAQ also must require an evaluation of the startup/shutdown exemption on the Utah County $PM_{10}$ nonattainment area. IPP Unit 3's impact on Utah County based on the "refined" modeling showed that the new Unit would cause a $PM_{10}$ impact of almost 2 μg/m$^3$, and the UDAQ significance threshold is

3 μg/$m^3$.  Thus, it seems possible that, with consideration of startup/shutdown emissions (as well as with additional years of meteorological data), IPP Unit 3 could have a significant impact on the Utah County $PM_{10}$ non-attainment area and be required to meet lowest achievable emission rate and obtain emission offsets to minimize its impact.

**Response:**

Regarding the Utah County $PM_{10}$ non-attainment area analysis, the modeling uses the combination of $NO_x$, $SO_2$, and $PM_{10}$ with all pollutants treated equally, and modeled as being non-reactive.  The total emissions release of these three pollutants over a 24-hour period is about 12% higher under startup conditions (52,247 lbs/day) than under normal operations (46,573 lbs/day).  The refined CALPUFF modeling showed that roughly 2 out of the available 3 μg/$m^3$ 24-hour offset concentration level was impacted by Unit 3 under normal operations.  Simple scaling of the normal operation impacts reveal that impacts from startups would be about 2.24 μg/$m^3$ in the non-attainment area and therefore will not trigger the need for offsets.

**Comment 19:  Class I Increment Impacts during Startup, Shutdown, Malfunction, and Maintenance (pg 50, p1)**

Further, UDAQ must require the evaluation of the startup/shutdown exemptions on the Class I PSD increments and AQRVs.  Without thoroughly analyzing the potential impacts that will be allowed by UDAQ's planned exemption from meeting BACT emission limits during startup, shutdown, malfunction and maintenance, UDAQ cannot adequately assess whether IPP Unit 3 will cause or contribute to adverse impacts on AQRVs or to Class I increment violations.

**Response:**

The UDAQ and draft EPA policy does not require an evaluation of the startup/shutdown emissions impact on the PSD Class-I increments or visibility.

**Comment 20:  Short-Term Emission Rates (pg 50, p3)**

As early as October 2003, the National Park Service notified UDAQ that IPSC should have modeled the maximum 3-hr and 24-hr average $SO_2$ emission rates for all increment-consuming sources in the Class I increment analysis.  The Park Service stated that when such sources were modeled at the appropriate emission rates, there are violations of the  3-hour average $SO_2$ increment at Capitol Reef National Park. On March 25, 2004, the National Park Service again notified UDAQ of those increment violations when the appropriate emissions were modeled (see p 5 of March 25, 2004 letter from the NPS to UDAQ, attached[1]).  Pursuant to R307-405-6(2) and R307-401-6(2), UDAQ cannot issue the Approval Order for Unit 3 without requiring emission limitations or emission offsets to avoid a violation of the Class I PSD increment at Capitol Reef NP.  There is no justifiable technical or legal basis for allowing IPSC to model

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[1] Note that the National Park Service letter erroneously claimed that, because IPP Unit 3's impact on the SO2 increment violations was below the "significant impact level" or "SIL," IPP Unit 3 would not be considered to cause or contribute to the increment violation.  However, there is no legal or regulatory basis in Utah regulations or in the federal PSD regulations to consider a source's impact on an increment violation as insignificant.  Further, this is contrary to EPA's interpretation of the law.  EPA Region VIII stated in an April 12, 2002 letter to the North Dakota Department of Health that the use of significant impact levels to allow a PSD permit to be issued in the case of an area showing increment violations is not consistent with the intent of the Clean Air Act's PSD program.  (See attached April 12, 2002 letter).

annual average $SO_2$ emission rates from contributing sources in its 3-hour and 24-hour average $SO_2$ PSD increment analysis for the affected Class I areas.

**Response:**

The October 2003 and March 2004 letters the commenter references were part of communications between the two agencies as they conducted parallel reviews of the Class I and AQRV analyses. A cooperative effort between the NPS, the PSD applicant, and the State of Utah began almost a year prior to the submittal of the NOI. The UDAQ, at the Park Service's request, brought the Federal Land Manger (FLM) onboard at that time to ensure that the Class I and AQRV methodologies developed for the IPP Unit 3 analyses would adequately address the concerns of both agencies. Comments such as those submitted in the two letters are working points between the two agencies based on a preliminary review of the modeling, and do not always represent the agency's final position. The UDAQ has discussed the applicability of the emissions data used in the preliminary analysis with the NPS, and found some of the values used to be questionable. The NPS's May 27, 2004, final comment letter to the UDAQ outlining their concerns with the proposed IPP Unit 3 addition, stated that "IPP-3 would not cause or contribute to the modeled 3-hour increment violation" and "this emissions issue should not effect the IPP-3 permit." The NPS's March 25, 2004, letter also included this statement.

The Clean Air Act requires that degradation to the atmosphere be limited to the "maximum allowable increase" in concentrations levels of $SO_2$, $PM_{10}$, and $NO_2$ set forth in the Act, and that increment consumption for existing sources of these pollutants shall be based on "actual changes in emissions since the baseline date." The NPS analysis uses Continuous Emissions Monitoring (CEM) data that includes the substitution of artificially inflated maximum hourly emission rate for periods when the CEM was offline, in order to meet the requirements of the Acid Rain emissions credit portion of the program. The NPS analysis also did not pair actual hourly emission releases in space and time with actual hourly weather data to verify that the increment violation would likely have occurred

At the time IPA established its Class I and AQRV modeling methodology with the NPS and UDAQ, the 1996 Fifth-Generation NCAR / Penn State Mesoscale Model (MM5) data set was the acceptable meteorological data set for modeling Class I and AQRV impact in the US. The data set provides nation-wide coverage of wind flow patterns across the country for the full year, and was developed and agreed upon through a cooperative effort between the EPA, the FLM's, and State agencies. This one-year data set also met IPA's legal requirement for long-range transport modeling at the time the methodology was developed. PSD modeling guidance further requires that estimates of actual emissions for existing sources be based on the most current two-year period representing normal operations at the facility. In the case of IPP, that period was 2000 through 2001. Since the emissions data could not be paired in time and space with the meteorology, the UDAQ elected to allow the use of an emission methodology that better represented normal operations at the facilities, and would result in concentration estimates in the Class I areas that had a higher statistical probability of actually occurring. The UDAQ believes that the increment consumption methodology used in the analysis meets the requirements of the Clean Air Act, and that no further Class I increment modeling for this permit action is warranted.

**Comment 21: Class I Area Analysis (pg 52, p3)**

IPSC failed to model the maximum short-term emissions from all contributing sources in its Class I increment analysis. The analysis is also incomplete because IPSC did not include all increment-consuming sources, the analysis did not model three years of meteorological data, and because IPSC did not model its startup/shutdown/malfunction/planned maintenance emissions for impacts on the PSD increments. IPSC failed to include any emissions from Unit 1 at the PacifiCorp-Hunter power plant.

**Response:**

See response to Comment #13, 16, and 20. The UDAQ did not require that NEVCO be included in the IPP analysis at the time the modeling protocol was approved, since the NEVCO application was not complete at that time. In addition, since NEVCO impacts on all Class I areas are below the Class I SIL for all pollutants (less than 5% of the Class I increment standards), it is not expected that their contribution would result in a Class I increment violation when added to IPA and other increment consuming source impacts. This same argument applies to other ongoing energy projects, which have submitted applications since the modeling for IPP was approved by the UDAQ. Pacificorp's Hunter Power Plant - Unit 1 was permitted under the PSD regulations. However, the unit began operation in 1978 before the major baseline date of August 17, 1979. Unit 1 has not undergone any major modifications since it originally began operation. The emissions and associated impacts are considered part of the baseline concentration and do not consume increment.

**Comment 22: Visibility Impacts (pg 53, p4)**

IPSC did not follow FLM recommended procedures to estimate Unit 3's visibility impacts on nearby Class I areas. Instead, IPSC devised a method to essentially discount the significant changes in visibility that the new unit will cause on nearby Class I areas. The IPSC analysis should also include the use of three years of meteorological data.

**Response:**

As stated in their May 27, 2004, letter to the UDAQ, the Park Service found no adverse impact to visibility in any of Utah's Class I area. The use of transmissometer data was not part of the original modeling protocol approved by the NPS. The analysis performed by the NPS also showed impacts less than 5% at all parks. A maximum change of 4.26% was predicted at Capitol Reef National Park when the 1996 MM5 data was used. Also, see response to Comment #13. Furthermore, the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) 2000 Report is guidance and not a rule. Specific circumstances associated with the exact procedures necessary to carry out the recommendations in FLAG often times must be addressed on a case-by-case basis. The permitting record for this application addresses these considerations.

**Comment 23: Visibility Impacts (pg 53, p4)**

The FLM (Park Service) refined the visibility impacts analysis for IPP Unit 3 by modeling a second year of meteorological data from the NEVCO Sevier power plant application. Based on the second year of data modeled, the FLM found that there were multiple days with a greater than 5% change in visibility at Capitol Reef and Canyonlands, and one day at Bryce Canyon. Further, UDAQ appears to be violating R307-406-3(1), as it does not appear that UDAQ considered the FLM's 1999 meteorological data visibility analysis of IPP Unit 3.

**Response:**

The analysis conducted by the NPS, as stated in their May 27, 2004 comment on IPP Unit 3, ultimately led to the determination by the NPS that IPP - Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301)*" in any of Utah's five Class I areas. Their analysis predicted a maximum reduction in visual range of 9.75% at Capitol Reef National Park. The UDAQ concurs with this determination.

**Comment 24: Visibility Impacts (pg 54, p4)**

(PG 54) Under Utah's regulations, it is the Executive Secretary's responsibility to determine whether a proposed source would adversely impact visibility in any Class I area and to "insure that source emissions will be consistent with making reasonable progress toward the national visibility goal referred in 40 CFR 51.300(a)." R307-406-2.

**Response:**

The requirements of 40 CFR 51.300(a) regarding new source review deals only with plume blight since at the time of the rule's conception scientific tools designed to evaluate the cause and effects of regional haze were not available. The UDAQ does require major PSD sources to perform plume blight modeling using VISCREEN or PLUVUE, in order to satisfy R307-406-2. The result of IPA's plume blight analysis indicated that all levels of potential impacts were within acceptable levels.

The UDAQ has committed considerable focus and resources to protecting the air quality in its Class I areas. The UDAQ has worked with EPA and the Federal Land Managers to develop 'Utah specific' haze methodologies using the most current modeling tools and guidance. In December of 2003, the UDAQ submitted a State Implementation Plan to EPA, in order to insure that future emission levels will be consistent with making reasonable progress toward the national visibility goals. It also adopted new rules for protecting visibility at that time.

**Comment 25: Cumulative Visibility Impacts (pg 55, p1)**

In the National Park Service March 25, 2004 letter, it indicated that they had modeled the cumulative impacts from IPP Units 1 and 2 with the proposed new Unit 3 and found numerous days with impacts greater than a 10% change in extinction at all five of Utah's Class I areas. The National Park Service thus concluded, "Emissions from IPP-1 and 2 significantly impact visibility at Class I parks in the region."

**Response:**

This permit action is for Unit 3 and does not involve Units 1 and 2, as Units 1 and 2 have not been modified in the ITA under consideration. In addition, the ultimate finding of the Park Service in their May 27, 2004 letter states that there is no adverse impact (see comment #23 response).

**Comment 26: Visibility Impacts (pg 55, p2)**

(PG 55) According to Utah regulation R307-406-2(3), UDAQ is to ensure that "source emissions will be consistent with making reasonable progress toward the national visibility goal referred to in 40 CFR 51.300(a)."

**Response:**

In addition to the response given to comment #24, the UDAQ would like to add that since no adverse visibility impacts were deemed by the NPS, no mitigation was required to reduce those impacts.

**Comment 27: Visibility Impacts (pg 55, p4)**

(PG 55) The FLM's modeling analysis shows that the existing IPP units are significantly impairing visibility at all of the state's Class I areas, and that IPP Unit 3 will impair visibility as well. According to the Park Service, if SCR technology were installed at IPP Units 1 and 2, NOx emissions would be reduced by almost 34,000 tons-per-year.

**Response:**

This permit action is for Unit 3 and does not involve Units 1 and 2, as Units 1 and 2 have not been modified in the ITA under consideration. The NPS specifically stated in the first page of its May comment letter that IPP Unit 3, "*would not cause an adverse impact on visibility (as defined in 40 CFR 51.301*

**<u>Responses to Environmental Group's June 30, 2004 comment letter on the addition of IPP - Unit 3</u>**

**Comment 1: Soils and Vegetation Analyses (pg 1, p3)**

The federal Clean Air Act and Utah regulations require a PSD applicant to provide a full and complete analysis of "the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification." The analysis must include those scientific studies that confirm the harmful effects that emission have on crops and native vegetation.

**Response:**

Adverse soil impacts in the vicinity of IPA are not expected to occur, since the maximum impacts from sulfur and nitrogen are several kilometers away, and very low compared to the secondary NAAQS. Impacts on vegetation are included in the NOI, and are adequate for purposes of fulfilling the requirement of the regulation (see section 8.15). Further, there were no comments from local farmers that indicated their crops were being impacted by IPP Units 1&2. Plume impacts from Unit 3 are less than the impacts from Units 1 & 2, therefore they are not considered adverse.